

SCENARIOS 3, 3a AND 5

SCENARIO 3: HORIZONTAL PRODUCTS

PROS

1. Provides information to facilitate efficient rate design. **(consensus agreed)**
2. State regulatory contract approval may ensure that utilities select cost effective contracts that serve their load profile.
3. May reduce market power amongst large suppliers, if regulated efficiently.
4. Requires competition amongst existing generation suppliers.
5. Allowing or requiring interstate competition may provide incentives to upgrade the existing transmission system.
6. Would provide greater certainty of cost recovery to incumbent utilities compared to traditional rate-making principles involving after-the-fact prudence reviews.
7. Assuming a competitive generation market, results in market-based rates for customers.
8. Would tend to facilitate and encourage supplier participation in the whole sale market.
9. Allows owners of individual units to bid directly. No supplier teaming required as with vertical tranches.
10. Would appear to be capable of producing stable rates for applicable customers within relevant time periods (monthly, quarterly, annually or multi-year periods
11. Allows for incorporation of RPS green Power requirements.
12. Would allow for longer-term contracts to be used to encourage development of new long-lived resources such as baseload coal plants and renewables.
13. A mix of contract lengths for various types of resources could mitigate rate volatility for applicable customers.
14. Would allow for easier incorporation of non-price concerns such as fuel diversity.
15. Utility has high flexibility in product procurement.
16. Less supplier sophistication required (i.e., suppliers can bid standard products))
17. Will work with unbundled rate designs and cost recovery tracking mechanisms.

CONS

1. Excludes “pre-packaged: offers that fit load shape and other obligations more closely.
2. LSE must manage load functions.
3. Possible added transaction costs.
4. Substantial portfolio risk is retained by LSE or its customers.
5. Lack of a long-term component could have the effect of economically favoring older generation as opposed to new builds and could potentially lead to adverse environmental consequences, if the result is akin to a perpetual bias toward older, more polluting generation.
6. Significant regulatory complexity involved in the review of the utilities’ management of its portfolio of products; likely to require new/enhanced regulatory staff skills in risk management.
7. Potential for stranded costs if some products are contracted forward.
8. Does not garner benefit of competitive risk management (i.e., third-party wholesale suppliers do not bear/manage risk other than ability to supply at offered terms).
9. Does not promote the construction of new intermediate and baseload generation due to the nature of contracts less than 5 years.
10. Does not promote utilities to purchase low-cost baseload generation long-term (10 or more years)
11. Does not promote significant transmission system upgrades due to the nature of short-term and intermediate tranches. This favors local generation or suppliers with proximity to the load.
12. Vendor diversity is only present when the term is long enough to allow new entrants.
13. Deals are subject to the competitiveness of the wholesale supply market.
14. Short-term contracts by nature effectively pass energy market risk to end-users.
15. Little or no consumer review or input.
16. Obligating utilities to renew 1-3 year contracts for electricity transforms the volatility associated with the spot market into a moving average fluctuation realized annually that potentially would be passed to end-users.
17. Could result in unreasonable prices if there is a lack of competition in the wholesale market.
18. Resulting prices could become significantly “out-of-market” over time
19. A failed auction without an alternative resolution may leave customer classes exposed to spot prices for some or all of their load for a period of time without alternatives available to them.
20. Selection and evaluation of supply portfolio is complex; complexity reduces transparency of process

21. Contentious regulatory process. Procurement decisions, hedging activities, and dispatch decisions easily second guessed based on after-the-fact analysis.
22. Utility must staff a trading organization for selling daily excess supply, buying economic energy when opportunities exist; or buying short-term supply to cover outages.
23. Final cost of supply not known until after the fact; this could hamper the ability for customers to shop the market
24. Potentially creates stranded cost risk for remaining customers due to unanticipated customer switching, etc.
25. Complex selection process can invite challenges under FERC affiliate policies.
26. Long term contracts that start out as market based but are not linked to subsequent market prices over time become “out of the market”, results in winners/losers and become contentious if not unsustainable.

FACTS

1. Does not address procurement of hedges.
2. Off-peak load is best served by baseload resources, which includes efficiently operated coal, nuclear, cost effective natural gas combined cycle units and some renewable sources incrementally. When feasible, utilities should put the lowest cost baseload resources under long-term contract. On-peak load is served by intermediate and peaking resources, which include oil, natural gas and various renewable sources.
3. Significant transmission upgrades and new large-scale new generators go hand-and-hand. Successful intrastate electricity commerce and low-cost, reliable electricity for consumers require that both are present.
4. Horizontal tranches are only adequate when they readily reflect the characteristics of the load being served.
5. Portfolio management is currently the responsibility of utilities. Transferring this duty to wholesale suppliers or independent power producers would be inefficient. Requiring suppliers to manage a portfolio of resources discourages entry into the wholesale generation market and improvements to existing transmission system. The procurement of electricity from various resources would be performed best by the utilities that can customize their choice of resources to the load it serves.
6. Could provide highly customized portfolio, but utility must “tailor it.” **(consensus agreed)**
7. Market power risk diminished.
8. Multiple year horizontal tranches mitigate exposure to spot energy market volatility and the volatility associated with some short-term transactions. **(consensus agreed)**
9. Risks and responsibilities remain largely with the utility.
10. Very similar to the IRP process and “Energy Plans.”

SCENARIO 3 a:

SMART PORTFOLIO MANAGEMENT

PROS

- 1. Allows more flexibility in mix of products.*
- 2. Provides for laddering of product types and terms which can dilute exposure to volatility or market power.*
- 3. Provides for a flexible plan, which may include long term and short term (including spot purchases) developed in a transparent public process making use of regulatory, utility, and other stakeholder expertise and including an assessment of wholesale supply contracts, market power, to manage risk on behalf of customers and suppliers accommodate changing supply, demand and market conditions over time.*
- 4. May include auctions where appropriate as well as RFPs for competitive procurement.*
- 5. Allows for non-price considerations to be included in portfolio planning, such as fuel and technology diversity, demand response programs, energy efficiency, and encouragement of new generator entry and investment and, as such, can enhance by security.*
- 6. Assuming a competitive generation marketplace, results in market-based rates for customers.*
- 7. Would appear to be capable of producing stable rates for applicable customers and suppliers within relevant time periods (monthly, quarterly, annually or multi-year periods)*
- 8. Allows for incorporation of RPS green power requirements.*
- 9. Enhances wholesale competition and market liquidity by opening up the procurement process to third-party suppliers through the utilization of competitive bidding.*
- 10 Facilitates generating companies with smaller or specialized asset portfolios being able to participate directly as suppliers to the utilities because the generating companies do not need diversified capacity mixes more critical to serving vertical tranches in order to participate.*
- 11. To the extent this scenario provides for a priori approval of the portfolio by the regulator uncertainty associated with after-the-fact prudence reviews is reduced.*

CONS:

1. Cons Nos. 1-2 listed under Scenario 3 listed above.
2. Not clear how to allocate risk up-or downstream associated with load shifting and following, e.g., if horizontal products' performance risk is borne by utility or its customers instead of by upstream supplier.
3. Laddering approach, coupled with requirement of *a priori* review of products by regulator, could result in very frequent ICC review to the point where the process is overly burdensome and not market responsive.
4. Implementation would be more complex than Scenarios 1 and 2 and would require more regulatory resources.
5. Important issues regarding goals, responsibilities, and risk allocation would need to be addressed prior to implementation.
6. Could result in unreasonable prices if there is a lack of competition in the wholesale market.
7. Resulting prices could become significantly "out-of-market" over time.
8. A failed auction without an alternative resolution may leave customer classes exposed to spot prices for some or all of their load for a period of time without alternative available to them.
9. May create heavy administrative costs and burden compared to other methods.
10. Approvals required for utility to adapt its supply portfolio to changing market conditions may result in inefficient portfolio management.
11. Non-standard supply bids (dispatch flexibility, unit contingent, terms, etc.) require complex evaluation criteria for each project type.
12. Politics, rather than economic market forces, could drive procurement policy.
13. Mandated fuel/technology diversity standards exclude some supplier from competing for portions of load requirements, even if they are lower cost suppliers.
14. Long-term contract for specified quantities creates stranded cost due to customer ability to switch. When market prices fall, customers leave utility service, leaving above market supply costs to be borne by remaining customers who now face increasing rates.
15. May involve significant counterparty risk, especially if procurement is through long-term supply contracts.
16. Creates a RPS standard of 10%.
17. 10% renewables is too large of a percentage to start with. Initial demand for renewable resources exceeds supply, and will put upward pressure on the price of renewable energy for which suppliers/purchasers will be locked into long-term contracts. Should consider a phased in approach.

18. Is the 10% renewables a capacity or energy requirement? If it is capacity, capacity equivalence must be taken into account. 100 MW of wind or photovoltaics does not have the same equivalence as 100 MW of CTG. If it is an energy requirement, the capacity issue from a reliability standpoint must be satisfied by conventional generation (gas, coal, nuclear, or hydro)
19. Must consider myriad of exceptions to any proposed renewable standard. For example, if the best wind resources are in northern IL and there are physical constraints to move that power to southern IL, what are options for southern IL utilities to meet the renewable requirement? Will there be a market for trading renewable energy credits?
20. What credit concerns are there for utilities continually having a portion of their load in the spot market?
21. Renewables have a long way to go before they can be given credit for reducing peak prices, this ties to the capacity equivalence issue.
22. Can lead to possible stranded cost issues on long-term contracts as a result of customer switching.
23. Bidders must add additional credit risk premium to contracts for tranches longer than 3-years. Current forward markets only exist out to 3-years and any price a bidder must submit beyond that is at a higher risk.
24. Long term contracts that start out as market based but are not linked to subsequent market prices over time become “out of the market”, results in winners/losers and become contentious if not unsustainable.

FACTS

1. Market power is asset at the outset of procurement plan formulation.
2. Suppliers of vertical tranches take on all generation-related responsibilities, including portfolio/risk management.
3. Risks and responsibilities would be shared between suppliers and the utility.

SCENARIO 5: MARKET VALUE INDEX (“MVI”)

PROS:

1. The MVI proposal reduces the need for regulatory oversight, other than setting the MVI's, on energy acquisition by the utilities (market mitigation would still be needed). **(AGREED)**
2. Assuming a good fit between the MVI and regional market prices for power, the process should police itself by providing a price to beat for the utility's supplier and competitors. **(AGREED)**
3. Assuming a relevant but independent index, the MVI should mitigate some of the affiliate concerns associated with power procurement and scheduling relative to the portfolio and the “tranche” procurement proposals. **(AGREED)**
4. Utilities would be free to play in the market in order to minimize their costs, and to take advantage of changing conditions to maximize their profits and minimize their risk. **(AGREED)**
5. Utilities have great freedom to arrange power and to hedge their risk. **(AGREED)**
6. Regulatory oversight is simplified. **(AGREED)**
7. To the extent that the MVI provides an independent, but relevant measure of the regional market's costs of delivered power, the MVI will reduce concerns about affiliate market power within specific utility territories. **(AGREED)**
8. Where the MVI is set in tandem with customer service “lock-in” switching risk is reduced. **(AGREED)**
9. Class-specific seasonal sets of MVI could be used to provide familiar rate structures for customers and as a vehicle to maintain price signals to customers regarding peak/off-peak/summer/winter costs to reduce load risk and provide price signals to customers. **(AGREED)**
10. The MVI structure provides an incentive for utilities to find the least cost power (unlike a simple pas-through structure. A sharing mechanism would ensure that these incentives translate into lower priced power for customers. **(AGREED)**
11. The regulatory burden and administrative costs of MVI are limited, once the MVI is set, because there is no need to review and approve LSE procurement actions before or after the fact. ICC just sets MVI-based price “cap” and ensures that ratepayers receive appropriate benefits when realized procurement costs are below those associated with the MVI cap. **(AGREED)**
12. Potential benefits to retail customers in terms of rate stability, if MVI is designed to include significant forward contracting or hedged supplies **(AGREED)**
13. Customers gain assurance of paying no more than the market price, assuming that MVI accurately reflects Illinois market conditions. **(AGREED)**

14. As a “benchmark,” MVI provides a transparent and relatively simple means of assessing some aspects of wholesale market and procurement performance. In particular, it may inform whether changes in the cost of locally solicited supplies are reasonable in comparison to price changes elsewhere over the same time frame. **(AGREED)**
15. MVI might form the basis of a usable price ceiling on wholesale prices when it is deemed that the local wholesale market is not competitive. (If the local wholesale market is competitive, then the MVI is likely to simply inject inaccuracy and/or unnecessary risks into the procurement and approval of local supplies). **(AGREED)**
16. MVI-based rate-setting would act as another mechanism to help ensure competitive, market-based rates (but places great risk on the utility). **(AGREED)**
17. MVI-based rate setting would help ensure that the utility incentives include cost minimization (but risks are greatly asymmetrical to opportunities **(AGREED)**)
18. May reduce costs associated with regulatory oversight of the utility’s procurement practices. **(AGREED)**
19. Theoretically, a market value index produces market based pricing for customers on a default service. **(AGREED)**
20. RTO’s do promote transparency, which will assist in a true MVI. Real time prices will become publicly available. **(AGREED)**
21. Some customers may see an energy CAP as a safeguard **(AGREED)**
22. Simplifies the regulatory oversight process. **(AGREED)**

CONS

1. MVI is not a procurement methodology. This approach should be associated with rate making methodology and should be discussed under rates.
2. It may prove difficult to design an MVI that adequately reflects reasonable differences between local and remote market prices (e.g., due to differences in the supply mix, reserve margin, congestion, load shapes, etc.). To the extent there are specification errors,” the MIVI will not be a good proxy for efficient local procurement.
3. If the MVI is set only occasionally (i.e., not calculated dynamically in comparison to each distinct procurement problem), it will reflect only market conditions prevailing at that initial time. In a volatile market, that MVI will not reflect the fair value of services procured over different horizons or at different points in time, even if those procurements are all competitive and reasonable.
4. If the MVI is set as fixed cap, it effectively forces the LSE to grant a **free** “call option” to customers. “Prodigal customers” may choose to leave their ARES and return to POLR if/when market conditions change relative to the (outdated) MVI. An ARES could be expected to charge a risk premium for the equivalent price protection in its retail products. Absent such a risk premium,

customer switching of this type is not efficient, but instead lead to reduced efficiency as it reflects increased demand for a product that is under-priced relative to its underlying costs.

5. As a cap on power procurement costs, the call-option nature of MVI (or any other price cap) shifts all upside wholesale procurement price risk to LSEs. This is problematic and potentially very costly to the distribution company, given the observed volatility of wholesale electric markets and the relative immaturity of the Midwestern bulk power market.
6. If market power is exercised in the MVI benchmark market (i.e., Mid-West Regional Market), then the index will reflect that market power. In essence, market power will be “exported” into Illinois and into the rates charged by Illinois LSEs.
7. Even if the index region is competitive, if the index is not a good proxy for competitive pricing behavior in the local region of interest, then the index may contain extra “headroom” leading to excessive rates charged to retail customers.
8. The market for relatively long-term products (e.g., forward contracts of 1 year or longer) may be far less liquid than the market for short-term (e.g., daily, monthly, or quarterly) products. The LSE may reasonably be asked to purchase a mix of short-term and long-term products at different points in time to lessen price risk. The MVI needs to reflect the mix of products purchased by the LSE and the expectations pertaining at the time of purchase. With thin forward markets, which are common to electricity trading in many regions of the U.S., it may be inherently difficult to develop an MVI benchmark that is relevant to both short-term and long-term procurements.
9. It is debatable whether an “MVI+10%” is an appropriate cap for the POLR product being procured for utility supply post 2006.
10. If the MVI were used as a benchmark for any purpose, adjustments would be needed for migration risk, regulatory risk, and any other requirements placed on the wholesale supplier other than what is currently in the MVI. Quantification of these costs would entail subjective judgment, and errors in estimating these costs could cause under-recovery for utilities or excessive charges to customers.
11. Politics could drive the MVI calculation methodology.
12. There may not be adequate forward market data to determine MVI calculations beyond 2 years out.
13. Difficult to get it right. History haws shown that the regulated MVI does not equate to true market prices. Disconnect between actual market and MVI make it difficult for ARES to compete, and can leave the regulated utility as the only viable option for customers.
14. Difficulty in converting wholesale market prices to retail market prices is part of the difficulty in “getting it right.”
15. Current MVEC only represents market snapshot. When the market changes, ComEd has to, with regularity, go outside of the tariff rules to protect the current ComEd deregulated retail market. (FRP, PPO power sales).

16. CAP's will, if not done correctly: reduce market participation, the chance for a successful deregulated electric market, and, in the long-run, increase prices for consumers.

17. Currently, the Illinois utilities have Power Purchase Agreements with their unregulated generation/marketing affiliates at fixed/known prices. Assuming these expire 12/31/06, an MVI cap could in fact increase the likelihood of curtailment. (Utilities may curtail as opposed to procuring energy above a capped rate and having the costs disallowed.).

18. Unclear how the MVI process encourages wholesale competition. The risk of revenue sharing, cost disallowance, etc., promotes another utility PPA with its affiliate.

FACTS

1. Despite the ICC having adopted formulas for utilities to compute a market-value based on published index data, at the present time there is no single acceptable Index available to accurately measure the market value of power and energy in all areas of the state. **(AGREED)**
2. Current MVI methodology does not include risk management costs associated with weather uncertainty, customer switching risk, and energy market volatility. **(AGREED)**
3. Difficulty in selecting the correct Index, that is, day ahead, monthly, yearly, 5 by 16, etc. **(AGREED)**
4. Current MVI methodology does not include transmission related costs (congestion, etc), reserve requirements or ancillary services costs in the Index price. (they do include a location adjustment and trans losses) **(AGREED)**
5. MV cap provision of PUA 16-111 (i) if tied to MVI may prevent utilities from offering a real time pricing option if hourly rates are capped at MV plus 10%. **(AGREED)**
6. MV cap provision of PUA if tied to MVI may prevent utilities from procuring contracts greater than one year duration. **(AGREED)**
7. MV cap provision of PUA if tied to MVI may limit procurement alternatives available to delivery only utilities to those that use the Index as the pricing method. **(AGREED)**
8. MV plus 10% may restrict or eliminate competition due to reduce "head room" since customers may be paying market value plus up to an additional 10%. **(AGREED)**
9. MV cap provision increases the risk profile to utilities by not guaranteeing cost recovery, which results in a loss of investment grade bond ratings thereby increasing their overall cost of capital, which would impact T&D rates. (Bond-rating agencies include a cost for imputed debt related to all PPA's. Fixed payments associated with power purchase contracts are treated analogously with a utility's long-term debt. When power purchases by a utility become significant, i.e., greater than 10 percent of their capacity or total sales, bond-rating agencies add some portion of the fixed payment obligations (actual demand charges specified in the contract or 50% of expected total contract payments) to the utility's existing debt to compute its total long-term debt liability. This process has the potential of adversely affecting a utility's capitalization structure and also its interest coverage ratios.

These adjustments may cause its bond-ratings to be downgraded leading to an increase in its cost of capital, which will further impact rates.) **(AGREED)**

10. MV cap may result in customers being subject to hour pricing as their only power and supply option. **(AGREED)**

11. MVI may not equal MV. **(AGREED)**

COMMENTS AND QUESTIONS

1. The following are the comments of Illinois Power Company on the presentation of ICC staff member Haas on the MVI - scenario 5.

2. This presentation raises a very important issue in the procurement discussion. Absent a substantial link between the method of cost recovery for purchased power and energy and the underlying method by which such power and energy is procured, what is the justification for mandating any particular procurement method?

3. Many of the other methodologies have carried with them an implicit tie to the ratemaking process. In this instance, this correlation is uncertain. If the MVI process itself establishes a cap on the rate of recovery for purchased power, then arguably, the LDC should be provided much greater latitude in managing its procurement activities – as the LDC bears the consequences of its actions, rather than the consumer. Should the LDC be faced with both a rate cap and a mandated procurement process, their ability to manage this risk is severely impaired.

4. The MVI serving as a cap also has potential negative consequences for consumers. Absent significant changes in the underlying mechanics of the MVI process, directly tying the LDC's purchasing practices to the MVI may likely result in substantially all of the power and energy acquired by the major LDC's in the State, being priced simultaneously. This likelihood could arise out of a desire by the LDC's to maintain as close of correlation as possible between the MVI (which will establish their retail rates) and their procurement costs. The risk to consumers in this comes from the potential volatility in the wholesale market which may arise when such large volumes of power and energy are simultaneously bid in a relatively small geographical region, on an annual basis – again presuming that LDC's acquire power and energy on the same cycle as their retail rates are established.

5. Since the MVI itself is a function of the forward market, a process whereby retail rates are established at precisely the same time that such a significant amount of power and energy is solicited from the market could be a cause for concern. The LDC's may have little incentive to make longer term purchases, given their inability to recover any costs in excess of an uncertain (at that time) future rate cap. To mandate that an LDC acquire power and energy across a time frame which differs from this regulatory price cap again imposes an inappropriate risk upon them which they are virtually unable to manage.